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Offshore EOR Initiatives and Applications in Brazil: An Operator Perspective

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Abstract

Implementing deep-offshore Enhanced/Improved Oil Recovery (EOR/IOR) is not an easy task. Bigger reservoirs, larger well spacings, injection/production/logistics constraints and difficulties to quantify benefits are some of the challenges that may be faced.

This paper presents the status and future vision for the main offshore EOR/IOR research and field application initiatives of a brazilian Operator. Most promising technologies and issues will be described. Overall research structure, as well as adopted strategies to test and implement those techniques will be addressed. Difficulties eventually faced will be mentioned.

The most promising methods in terms of water-compatible EOR are customized-composition waterflood, novel conformance control solutions and optimal reservoir management. Regarding gas-based technologies, the focus is on WAG flood, foam, subsea gas/liquid separation/reinjection and gas injection optimization.

Background and Context

Brazil has a long tradition on the research and application of special recovery methods. Thermal, chemical, miscible, microbial and other special methods were studied, piloted or implemented targeting onshore fields. Several R&D projects and single-well tests, at least ten pilots and two field-wide applications have been implemented since 1969. Cyclic steam stimulation, steam flooding and water shut-off were the most prosperous technologies.

Some key success factors and lessons learnt may be remarked. In general, it's important to:

- Understand the underlying mechanisms of each method
- Test or develop mathematical models that represent the main mechanisms
- Incorporate these models in reservoir simulators
- Perform adequate EOR and target-field screening
- Customize the chosen EOR technology to the target-field

- Adapt or build-to-suit production facilities
- Deploy field-pilots that can provide results in a reasonable timeframe
- Integrate corporate strategic drivers, R&D and assets
- Carefully plan, implement & monitor EOR projects
- Increase deployment pace
- Have wisdom and resilience to record successes and failures and learn from them

The success of an EOR application will depend, besides all factors listed above, on a good description of the reservoir and on an adequate characterization of its heterogeneities. The lack of knowledge on these aspects can lead to poor results, as well described in the literature.

Since the shallow-water discoveries in the sixties and mainly after Campos Basin first exploratory results in the mid-seventies, brazilian offshore oil production has seen a steep increase, from 200k to around 3MM bopd. Now, with the development of Pre-Salt Province resources, which is currently responsible for almost 65% of total production, offshore activity has more than ever assumed a prominent role in the national scenario, accounting for 96% of all produced hydrocarbons. Supergiant ultra-deep water fields, like Lula, Buzios and Mero, are ramping up and offshore production will keep increasing in the upcoming years.

This scenario imposes huge challenges to adapt or develop new EOR technologies that could be applicable. Direct replicating old-fashioned methods may be, for many reasons, unfeasible. On the other hand, prizes may be attractive, not just for Pre-Salt greenfields, but also for Campos Basin brownfields, still very productive.

Offshore EOR Challenges and Opportunities

The complexity of implementing an offshore EOR project increases significantly as we move to ultra-deep waters. The following challenges may be mentioned:

- Larger reservoirs, and consequently higher treatment volumes and EOR costs
- Fewer, more spaced, frequently subsea-completed and expensive wells
- Irregular well patterns
- Longer response times
- Difficulties to isolate and quantify EOR benefits, as changes in injection/production schedules are almost unavoidable in such longer timeframes
- Technical and financial hurdles caused by platform and subsea operation
- Logistic issues
- Injection/production constraints
- Facilities less prone to revamps or additional equipment that could enable EOR at brownfields
- Less tolerance to impacts on topside processes (e.g.: oil/water separation)
- Need of extra appraisal and data acquisition to reduce uncertainties and mitigate risks before sanctioning EOR projects

Additionally, maturity of offshore basins brings new challenges to the continuity of production. Among those challenges are the capacity to process large amounts of produced water and the demand for revitalization of production facilities, including topside, subsea and new wells.

This context turns EOR application into a difficult task in this kind of venture. On the other hand, as offshore fields tend to have bigger OOIPs to pay off the larger upfront CAPEX and OPEX, EOR prizes also tend to be more attractive. Even small recovery factor increments in these large fields may represent a significant increase of NPV.

One recommended practice is to think about EOR in advance. For most EOR technologies, the sooner the deployment the better. Technically speaking, it's much easier to guarantee a good reservoir sweeping from the beginning or even to avoid oil trapping in the rock pores than remobilizing it afterwards.

Additionally, designing the necessary EOR facilities in new production units, or even providing them some flexibility that could allow future EOR deployment tends to be much easier than performing on-site or docked extensive retrofits.

Corporate and R&D Programs

To address the challenge of boosting offshore production, two strategic corporate and R&D programs were settled.

The first of these corporate programs focus on the revitalization and recovery enhancement of Post-Salt Campos Basin's waterflooded sandstone mature fields (Silva et al. 2019), aiming to:

- Deepen the diagnosis of the recovery factor per reservoir
- Establish recovery targets and ambitions for each reservoir
- Identify initiatives to boost recovery
- Provide the technical support to deploy the projects

Some initiatives are:

- Improvement of well damage prevention/remediation practices
- Water injection optimization
- Water treatment debottlenecking
- Use of 4D seismic to identify remaining oil
- New technology deployment
- Application of selected EOR/IOR techniques
- Integrated reservoir & subsurface simulation tools for production management
- Substitution of production facilities & evaluation of supplementary projects
- Extension of concession contracts
- Speed-up of project implementation
- Cost reduction

New opportunities are characterized by mid-term supplementary projects, mostly infill drilling or improvements on artificial lift systems, and long-term challenging projects involving IOR/EOR methods.

The second corporate program dedicates to enhance the oil recovery of Pre-Salt water & gas flooded carbonate oil greenfields, increasing their profitability. The program structures and monitors multiple actions in a systemic work.

Some initiatives include:

- Static/dynamic reservoir characterization & modelling (e.g.: structural/geological interpretation, special seismic techniques, field-wide water and gas tracing; sampling and laboratorial rock & fluid tests). In early stages of development, every reservoir has several uncertainties. This is even more critical in carbonate rocks, which usually present a higher degree of heterogeneity than sandstones.
- Reservoir management (e.g.: injection/production optimization, smart completion)
- EOR/IOR (e.g.: WAG, foam, customized waterflood, Autonomous Inflow Control Devices-AICDs)
- Flow assurance
- Increase of exploitation rate

R&D programs were conceived to provide technological solutions that could support those corporate strategic drivers, saving part of the resources to disruptive innovations and digital technologies.

EOR Technology Focus

Considering the particularities and constraints imposed by the deep water offshore scenario, the most promising technologies are those that:

- Use, in the simplest and most environmentally safe way, the two most abundant resources available offshore: seawater and, if feasible, produced or imported gas
- Require the least modifications to production facilities and supply logistics
- Present relatively low implementation risk
- May be applied as local treatments (well scale), as they generally involve lower treatment volumes and costs and provide faster results. In addition, they require less and temporary changes of production facilities
- Are inspired by disruptive processes or technologies, with significant potential benefits

According to these drivers, the focus was on six most promising technologies that fit our present and future challenges. These techniques present different Technological Readiness Levels (TRL) and will be described with more details in the next paragraphs.

Water-Alternating-Gas Flood (WAG)

The development strategy for some deep-offshore fields located in the area known as the Santos Basin Pre-Salt Cluster (SBPSC), southeast Brazil, includes the use of Water-Alternating-Gas (WAG) technology (Pizarro and Branco 2012). In this province, oil has significant amounts of associated gas, with CO_2 molar contents that vary from zero to as much as 40%. For environmental reasons, all this carbon dioxide cannot be vented to the atmosphere. The solution is to reinject it, either after separation or in mixtures with natural hydrocarbon gas. Then, WAG flood is a recovery technique that also leads to enhanced reservoir pressure maintenance, more flexible produced gas management strategies and environmental compliance.

In WAG method, gas and water slugs are alternately injected according to predetermined schemes. Gas plays the main role of reducing oil saturation due to different mechanisms, particularly oil swelling/ viscosity reduction, oil stripping and vanishing gas-oil interfacial tension. Water slugs control the adverse gas mobility, that can, thus, diverge to different rock portions and contact additional oil. This alternation of water and gas injections results in a synergistic effect that increases mobilization, displacement and sweep efficiencies (Caudle and Dyes 1958).

Nowadays eight fields in Santos Basin consider WAG flood in their development plans and three already started the injection. Around 13 million tons of CO_2 were so far reinjected.

Lula supergiant carbonate complex, discovered in 2006, was the pioneer, having started its WAG flood in 2013. It is located in deep waters (2200 m), approximately 230 km from the coast and occupies about 1523 km^2. Reserves are estimated in 5-8 billion barrels. The oil has a good quality (28-30 API) and contains a significant amount of associated gas (200-300 m3/m3). CO_2 content in the gas averages 10%. Nine FPSOs are now installed in this area with a total current production around 900.000 bopd.

Lula scenario is particularly suited for miscible gas injection. The relatively low reservoir temperatures (60 to 70°C) and the high original reservoir pressure favors an efficient oil miscible displacement by enriched CO_2 streams or even by hydrocarbon gas (HC).

Some characteristics of this project are:

- Phased development for risk mitigation, optimization of production systems, expenditure versus revenue balancing and cash flow acceleration
- Robustness/flexibility added to production systems in order to manage uncertainties, particularly for WAG floods. Examples are: selective injection/production by intelligent completion, possibility to convert or connect additional wells, choice of injected fluid (water, gas or WAG), provision of gas discharge wells, compressors designed to allow full gas reinjection
- Extended well tests (EWT) & multi-well pilots to gather information for definitive systems
- EOR planned in advance to enable offshore implementation
- CO_2 separation using the permeation through membrane technology

In terms of field characterization for WAG, the following aspects may be remarked:

- Proper static and dynamic characterization was a primary driver, due to reservoir complexity
- Special attention to dynamic modelling through EWTs
- High resolution seismic imaging and 4D seismic to monitor fluid motion and WAG injection
- Extensive fluid sampling program for fluid characterization and flow assurance
- Interwell gas and water multitracer injections and monitoring
- Specific gas/WAG flood laboratorial tests, such as PVT, miscibility, core multiphase flow, geomechanics and rock-fluid interaction experiments (Caudle and Dyes 1958; Vieira et al. 2016; Vieira et al. 2019).

In 2013, a production pilot project was initiated in Lula field by the deployment of a production system with a total of 9 wells (6 producers, 1 gas injector and 2 WAG injectors). The main objectives were the evaluation of some operational issues at field scale, such as:

- Cycling operability
- Reduced injectivity (mainly water injectivity loss after gas cycles)
- Early gas/water breakthrough in production wells
- Corrosion due to carbonic acid
- Scale deposition, potentially worsen by rock-fluid interaction effects
- Asphaltene precipitation, wax deposition or hydrate formation upon WAG cycling
- Extended evaluation of gas processing plant and CO_2 removal system

Additional expected insights were:

- WAG performance, mainly assessed by observing GOR and BSW responses due to cycling
- Practical relevance of special supporting characterizations, such as tracers and 4D seismic

In five years, five WAG half-cycles were performed in the pilot, with no major operational or reservoir issues. WAG pilot was then extended and around 50 half-cycles were performed in 17 different wells.

Some aspects to be remarked from this application are:

- Water and gas injectivities in WAG cycles varied case by case, but, in general, no detrimental loss has been observed at field scale
- Field results attest WAG effectiveness to control gas mobility, allowing smoother gas and water production profiles and preventing topside bottlenecks or production losses.
- Injected gas & water tracers contributed to the analysis of GOR and BSW behaviors due to cycling and to the overall dynamic characterization of the field
- Time-lapse seismic helped to understand WAG flow in the reservoir. Fluid fronts can be detected by the technique, although it still misses enough vertical resolution to monitor gas gravity segregation

Foam Flood

Depending on reservoir heterogeneity levels, gas mobility control provided by WAG may not be enough. Particularly in the offshore scenario, due to the lower well density, adoption of additional techniques to slow down gas flow is desirable. Foam flood is a potential alternative.

Foams are dispersions of gas in water, generally stabilized by surfactants, that have apparent viscosities bigger than water or gas viscosities alone. It improves oil recovery and gas trapping, potentially enhancing sweep in scenarios of channels, vugs or gravity override.

Many different injection modes exist: Foam-Assisted WAG (FAWAG) - where foam is generated in-situ by dissolving surfactants in water cycles, Co-Injection – where foam is also obtained in-situ, but by simultaneously pumping water with surfactants and gas, and Pre-Formed Foams – with foam formed at the topside. Foam properties and uses depend on injection mode.

One of the most interesting aspects of foam flood is the selective mobility reduction, which means that the higher the thief zone permeability the more intense is gas mobility control. This behavior results in more stable displacement fronts, better sweeps and higher recovery factors.

Challenges for foam flood study and application in the field are related to:

- Comprehension of rheological behavior and flowing physics in porous medium
- Development of reliable mathematical models, enabling better risk and benefit assessments
- Improvement of stability and propagation in reservoirs, mainly when in contact with oil
- Prediction and mitigation of eventual impacts of surfactant production on topside equipment

Increase of fundamental knowledge through laboratory and field tests, as well as incorporation of such knowledge in numerical models and reservoir simulators are ways to overcome these challenges.

At this moment, foam flood is in R&D stage in the Company and is considered a low TRL technology due the above-cited challenges. Experiments to systematically investigate the impact of total flow rate, foam quality and rock permeability were already done.

Optimal Reservoir Management

Most offshore fields that we operate make use of several devices and techniques to achieve a sound reservoir management. Data acquisition programs, extended well tests, chemical tracer injection, use of remote pressure gauges, intelligent completion equipped wells, 4D seismic and others features were implemented to guide and maximize the value of field projects (Pizarro et al. 2017). Besides all those actions, there is still room for improvement, as will be described below.

The conventional continuous water or gas flood strategies are normally based on voidage replacement for pressure maintenance and oil sweep, not taking into account any concerns related to the distribution in time and space of the injected fluids with the aim to improve recovery. One key point, though, is that rock heterogeneity, fluid compressibility and reservoir compartmentalization matter for the ideal fluid injection recipe. A non-optimum injection may lead to excessive water or gas production, oil bypassing and bottlenecking of topside facilities, which is even more critical in the offshore scenario.

Optimal Reservoir Management (ORM), a technique that couples optimization algorithms and reservoir simulation, can be applied to maximize exploitation performance and deliver well controls applicable to field operations.

ORM technique has been implemented in an important waterflooded field offshore Brazil (Campos Basin), were cumulative oil production was maximized by optimally controlling water rates through injection wells (Oliveira et al. 2019). Main characteristics were:

- Actuation exclusively on injection rates (11 wells during 20 years of forecast after the historical period)
- Injection rates varied in time, honoring operational requirements of smoothness
- Non uniform control steps
- Geomechanical limits on injection pressures were considered to avoid loss of rock integrity
- Platform constraints on overall production and injection were imposed
- Approach deals with reservoir uncertainties described within a large set of calibrated simulation models

To deal with the computational burden associated with performing well-control optimization with geological uncertainty, a representative model selection technique based on minimizing the total weight of the discarded models was used.

Numerical implementations of the model-based ORM under uncertainty have shown benefits in total oil production in 20 years of operation that averaged 4% over the base waterflood strategy applied at that time in the target-field, with concomitant reduction in water production and injection.

A pilot test in the actual field has been deployed to verify the consistency between modeling and reality and guarantee that the gains forecasted in the study were feasible. The pilot area, with two injectors and two producers, has been screened based on aspects related to geophysical description, reservoir connectivity and operational constraints. After eight months of operation, pilot results showed clear coherence between models and reality within the uncertainty range expected to the reservoir of interest (Figures 1 & 2). The pilot provided more confidence on field applications, leading to a broader perspective for full-filed implementations. Results suggest robust benefits and large scale application shall take place soon.

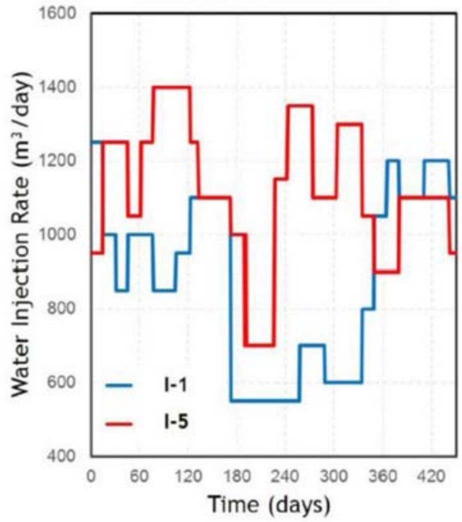

Figure 1—Optimal water injection rates for the pilot area.

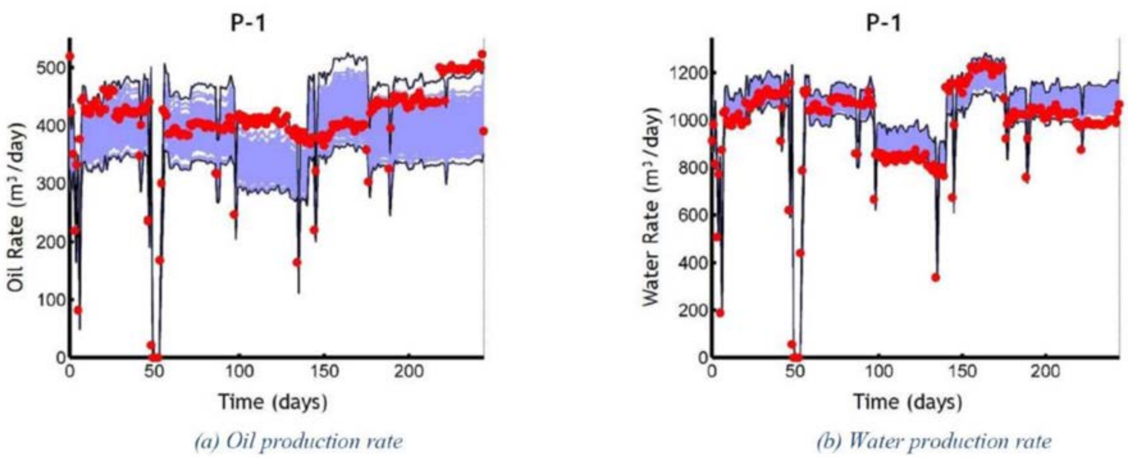

Figure 2—Comparison between oil and water production rate measurements at Producer P-1 and forecast from the 300 reservoir models used for uncertainty assessment: red dots represent the observed data; solid blue lines correspond to the simulation run for each model and solid black lines indicate the maximum and minimum responses for simulation.

Some key aspects may be remarked:

- Optimization tends to be more effective when controls are applied both on producers and injectors. But, from the operational point of view, it is easier to implement in the field modifications only at injectors. Performing frequent modifications at producers is not a trivial task in practice, since maintaining production stability may become an issue, which is typically overlooked in optimization studies.
- There are intentions to replicate the methodology to other offshore waterflooded fields. At least five important fields are currently under optimization studies.
- The technology and its associated digital platform is being expanded to deal with WAG optimization in Pre-Salt fields, where an analogous strategy will be applied for water and gas injection recipes. Typical variables of this EOR technique will be optimized, such as cycle lengths and WAG ratios. In this case, the objective function will not only maximize oil production but also minimize GOR at producers, one of the main targets of WAG floods.

Subsea Gas-Oil Separation

Largely undersaturated deep offshore fields with high productivity indexes, GOR and CO_2 concentration generally ask for large production facilities, with complex gas processing and separation plants.

In this scenario, subsea solutions for gas-oil separation are desired to reduce weight, footprint and complexity of such topside facilities, hence boosting liquid processing capacity, extending oil production plateau and accelerating oil recovery by favoring deep offshore gas-based EOR, like WAG.

Produced fluids with the above-mentioned characteristics and at high pressure level splits into two phases: one phase rich in CO_2 and another phase rich in hydrocarbons. Once these two phases are formed, they may be segregated by gravity or other separation processes enhanced by additional forces, such as centrifugal.

Proper setting of operation conditions enable the subsea separation and reinjection of a major fraction of this CO_2-rich phase as a dense fluid, as it presents a specific gravity typical of a liquid, allowing the use of pumps for its direct reinjection from the seabed. GOR of the hydrocarbon liquid phase (oil) is significantly lower than the feed. Thus, the recovered oil stream pumped up to the production unit will be less gassy and thus require smaller and simpler processing plants.

We have developed and patented a technology that takes advantage of the this peculiar fluid behavior (Passarelli et al. 2019). The concept was tested by static laboratory experiments and pilot dynamic conditions.

Results of the pilot testing program have confirmed that the separation observed previously at static condition in the laboratory also works at dynamic conditions. Oil yields and dense gas phase properties obtained from the tests reproduced the behavior forecasted by tuned thermodynamic models. Therefore, dense gas separation at high pressures has the potential to ultimately increase oil production, by debottlenecking topside facilities in already installed production units or changing the whole design of new ones.

The technology will be further qualified in the upcoming years by numerical simulations and a subsea prototype in one Pre-Salt field. Integration to existing FPSOs, validation of centrifugal pumps that will reinject the separated dense gas and mitigation of flow assurance issues in the case of eventual shutdowns and start-ups are some challenges of the next steps.

After its qualification stage, expected to finish in 2026, this technology will enable a new generation of FPSOs designed for high-GOR and high-CO_2 content reservoir fluids, taking advantage of the large amount of produced dense gas subsea-removed. These FPSOs will be able to host larger oil processing capacities without the need of huge and complex gas processing plants, increasing operational safety and reducing CO_2 emissions per barrel of produced oil.

Customized-Composition Water Flood

In this technology the composition or whole salinity of the injection water is altered to trigger rock-fluid interaction phenomena that are responsible for incremental recovery (Bartels et al. 2019; Katende and Segala 2019).

In spite of numerous laboratory and numerical simulation studies, as well as some field-pilots attesting the potential benefits of the technique, its underlying mechanisms still seem to be controversial. Fine migration, electrical double layer expansion, multicomponent ion exchange and effects caused by changes in pH are some phenomena used to explain customized water results. Although no consensus seems to exist on the main mechanisms or combination of mechanisms that are responsible for the production enhancement, most of them result in rock wettability alterations towards a more intense water wetness.

The technique presents the following benefits:

- No extra chemicals should be acquired, transported, dissolved and injected in the field
- Reduced or null environmental impact

- Full compatibility with upstream or downstream processes
- May be combined with all water-based EOR methods
- May enable or boost other offshore EOR processes due to the lower salinity (e.g.: polymer flood)

We study this technology since 2014, both for sandstones and carbonates. Our results show that the injection of the customized-composition water indeed causes a wettability alteration which is translated into changes of relative permeability curves. We generally observe that oil relative permeability curves are altered in a greater extent than water curves (Figure 3). Increased recoveries are seen even with limited injected pore volumes of water (Figure 4). Higher benefits are obtained when the customized water is injected in secondary recovery mode, rather than in tertiary mode (4% incremental recovery factor versus 1%).

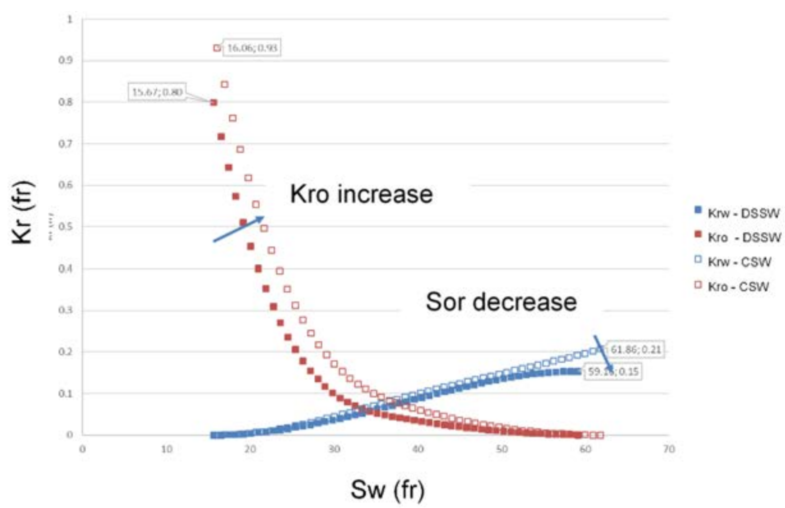

Figure 3—Water/oil relative permeability curves of a rock sample flooded by desulphated seawater (filled squares) and customized composition seawater (hollow squares).

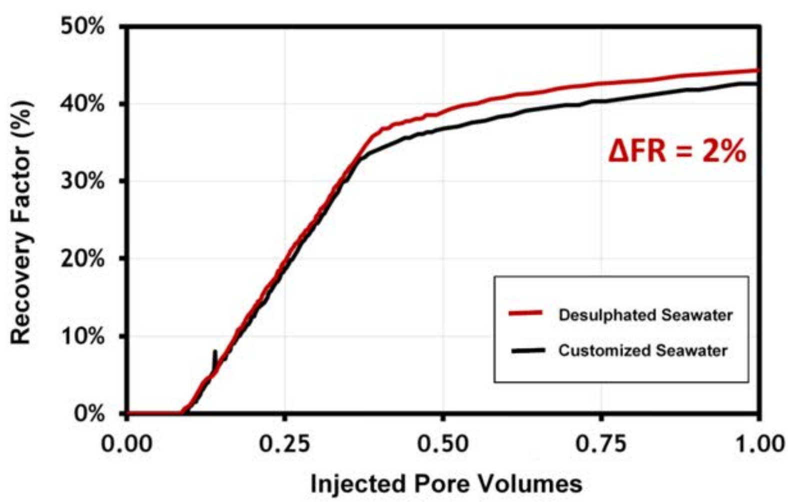

Figure 4—Laboratorial recovery factors for a rock sample flooded by one pore volume of desulphated seawater and customized-composition water.

Regarding carbonate rocks, a special methodology was developed to enable the execution of reservoir condition tests with CO_2, avoiding the drawbacks of rock dissolution. In addition to core displacement tests, scaling and souring potential studies were also done, having found no detrimental effects.

Engineering studies were performed to evaluate the cost of a desalting unit in comparison to the cost to convert a sulphate-removal unit into a desalting unit. This study have shown that the unit conversion, especially onsite, is very complex and costly, generally turning the application in brownfields economically unfeasible. In greenfields the situation is different. There is virtually no difference in terms of CAPEX of sulphate-removal and desalting plants. On the other hand, the OPEX of desalting is a little bigger, but might be compensated by eliminating the desalting plant used for oil washing.

Field implementation in greenfields is considered of low risk, in the sense that if the technology doesn't work there would be no other technical or economic impacts for the project. But one drawback is that the present desalting technologies do not tolerate residual oil in water, thus excluding applications in case of water reinjection.

Next step is the execution of one-spot EOR tests based on single-well tracer injections to validate laboratory results. Three tests are being planned for 2020.

Conformance Control

Reservoir heterogeneities, represented by higher permeability strata or fractures, are among the most important causes for low sweep efficiencies in waterfloods. Mobilizing bypassed oil left behind by water flowing through shortcuts between injectors and producers is one of the main industry challenges.

Water coning around producers is also an issue, as excessive water production overloads topside processing capacity.

There are different possible technical solutions for these problems, depending on each particular case:

- Local treatments near injectors: blocking polymeric gels
- Local treatments near producers: relative permeability modifiers (RPM).
- Treatments acting far from injectors or producers: deep conformance control technologies

We have no activity involving gel technology for the offshore scenario. For RPM and deep conformance there are R&D efforts to develop new products or adapt existing solutions for this context. They will be better described in the next paragraphs.

Relative Permeability Modifiers. The use of blocking technologies, like gels, for producer wells is not recommended due to the risks imposed to oil production. Water conformance close to producers is usually controlled by Relative Permeability Modifiers.

In this technology, alternated injections of polymer solutions containing molecules with opposite electrostatic charges or crosslinking agents are done, generating a hydrophilic multilayer over the rock pores that tends to swell in contact with water. The first polymeric layer should have a charge that opposes to that found on the rock, in order to adsorb onto it. A radius around 1-3 meters is treated. It results in a preferential reduction of the water relative permeability (Krw), with little effects on oil permeability (Kro), a behavior known as Disproportionate Permeability Reduction (DPR). Water streamlines are changed, causing its invasion in pores still oil-saturated. The higher the number of polymer layers the lower the resulting Krw. If thickness is excessive, though, Kro may also be affected. Additionally, the more permeable the rock, the higher should be the polymer molecular weight to obtain the same level of Krw decrease.

We developed a proprietary RPM formulation that was extensively applied onshore, with a success index over 70%. A customization of this technology is in R&D stage, aiming at high permeability sandstones.

Deep Conformance. Gel and other similar technologies present limited penetration. As treatments are placed close to injector wells the diverted water may quickly return to the original path.

Barriers in different positions of the reservoir could be possible if the injected chemicals had a retarded activation mechanism (Al-Maamari et al. 2015). This technology is known as "Deep Conformance" and triggering usually happens by pH or temperature changes.

In partnership with a brazilian university, we developed an elongated-micelle nanostructured, thermoresponsive and low cost deep conformance system. It is composed of two surfactants that form round micelles at low temperature, thus with viscosity similar to the injected water. As it penetrates in the formation and the injected water gets hot, these surfactants assume a linear conformation, increasing molecular friction (Figure 5). Depending on surfactant concentration, viscosity may be raised tens to hundreds times its original value, causing divergence or even blocking the high permeability channels.

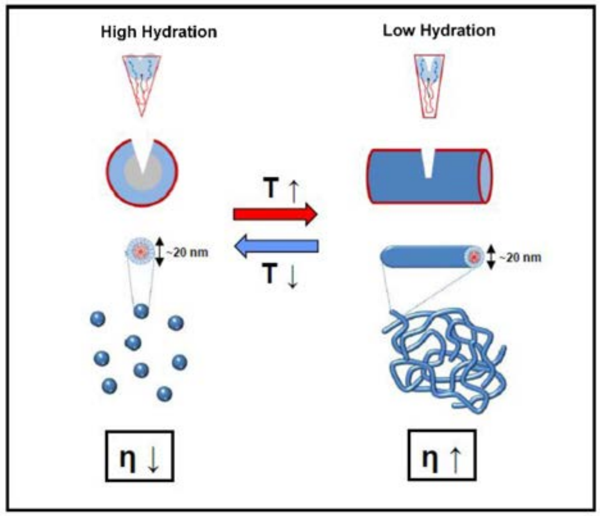

Figure 5—Mechanism for elongated micelle generation.

Another interesting characteristic of the elongated micelles system is that its rheology behavior may be further modulated by other properties of the medium, like salinity and pH, or by the concentration of the surfactants in the formulation (Destefani et al. 2018). So, it's possible to tailor the formulation to the target reservoir or to the desired activation distance from the wellbore, providing a great versatility to the system.

Some additional advantages can be remarked:

- The fluid may be injected at low viscosity, not impacting injectivity
- The effect is totally reversible. If temperature is further decreased or breakers that change the associative structure of the micelles are injected, the viscosity of the system may be lowered again
- There is also no need for crosslinkers

Laboratory tests were performed in a target unconsolidated sandstone sample of an offshore oilfield, with temperature around 65°C. Results showed that an in-situ viscosity of 1215 cp was obtained when the product reached reservoir temperature (Resistance Factor, RF=2616). Further desulphated seawater injection revealed a Residual Resistance Factor-RRF of 21.7, denoting a significant and persistent reduction of water relative permeability. These values are compatible with those obtained by other deep conformance technologies, such as PPG-Preformed Particulate Gels (Saghafi et al. 2016; Imqam et al. 2018). Breaker injection reduced the RRF to 6.9.

This technology proved to be successful at lab scale and is considered ready for a field pilot. Formulations that work up to 80°C are validated and others resistant up to 100°C are under testing. The challenge is to prove the effectiveness in case of a greater than expected surfactant dilution, providing robustness to the field solution.

Conclusions

Due to our portfolio predominantly offshore, including brownfields from Campos Basin and greenfields from the Pre-Salt Province, we have established strategic and R&D programs to boost offshore EOR.

Lesson learnt from past onshore initiatives are accelerating offshore deployment.

One of the most important drivers is related to the wise use of the two most abundant offshore resources in our case, water and gas, avoiding techniques that demand lots of chemicals and logistics, as fields are quite big and distant from shore.

Considering water-based EOR/IOR, focus is being given on customized-composition waterflood, optimal reservoir management and conformance control, including, in this last case, a novel solution based on thermoresponsive nanotechnology.

For gas-based EOR, targeting many Pre-Salt supergiant fields, focus is being given on WAG and supporting technologies, like foam flood, subsea gas separation/reinjection and WAG optimization.

Offshore WAG flood is a reality, with several successful cycle switches. Having started on the bench, with complex rock and fluid specific characterizations, passing through numerical modelling & simulation and field tests, the technology is now starting to be more broadly applied in our assets.

Optimal reservoir management for waterflooded reservoirs was also piloted and will be soonly applied field-wide. Other mentioned initiatives are mainly in R&D stage, but showing promising results.

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